IPP Water Supply. IPA owns off-site water rights that yield approximately 45,000 acre-feet per year. This amount exceeds the annual water requirements of the Intermountain Generating Station and the Intermountain Converter Station. A reservoir at the Intermountain Generating Station, in combination with groundwater wells, can provide sufficient water to operate for approximately three months at average plant loads.

Permits, Licenses and Approvals. According to the IPA, the IPP has been designed, constructed and operated in compliance with all applicable federal, state and local regulations, codes, standards and laws, and all principal permits, licenses and approvals required to construct and operate the IPP have been acquired, including permits relating to air quality and rights-of-way on federally-owned land.

Emissions. The Intermountain Generating Station's boiler and flue-gas cleaning facilities have been designed and constructed to meet applicable federal and state emission regulations. The boilers have been designed to meet stringent regulatory emission limits for oxides of nitrogen. The flue-gas desulfurization equipment (scrubber) for each unit consists of a wet scrubber system using a limestone reagent designed and constructed to remove at least 90% of the sulfur dioxide before discharge to the atmosphere from a chimney 710 feet in height. The flue-gas particulate control (baghouse) equipment for each unit consists of three modular fabric filters utilizing reverse air for cleaning. The equipment has been designed and constructed to remove at least 99.75% of the particulate material.

Waste Management. Substantial federal, state and local legislation and regulations regarding various aspects of waste management are in effect. Federal laws as set forth in acts such as the Federal Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act, as amended by the Superfund Amendments and Reauthorization Act, impose strict liability for cleanup costs and damages regardless of time or location on generators, transporters, storers and disposers of hazardous waste. Many day-to-day activities connected with the generation and transmission of electricity generate both non-hazardous and hazardous wastes. Intermountain Power Service Corporation, under the direction of LADWP, has established a waste management plan for the IPP. The plan is designed to assure that the IPP's present and future operations conform to applicable waste disposal regulations. LADWP has also assessed IPP properties for potential liability arising from past, latent contamination. LADWP has indicated that its waste management program complies with all federal, state and local statutes and guidelines and all applicable permit requirements.

Operating Experience. The IPP facilities have operated to date with a high degree of availability, exceeding the average of coal-fired generating units of comparable size. During the most recent Fiscal Year, the IPP operated at a net capacity factor of 87.9%. In the Fiscal Year ended June 30, 2009, the IPP Generating Station provided 726,798 MWh of energy to the City at an average cost for delivered power of $47 per MWh (excluding transmission costs).

Southern California Public Power Authority

The following information has been obtained from SCPPA and sources that the City believes to be reliable, but the City takes no responsibility for the accuracy thereof.

SCPPA Palo Verde Nuclear Generating Station ("PVNGS") Interest. The City has contracted with SCPPA for a 9.9 MW (4.4%) entitlement of 225 MW SCPPA PVNGS Interest (as defined herein). This resource provides the City with approximately 65-75 GWh of base-load energy annually. The City has entered into a power sales agreement with SCPPA which obligates the City to pay the cost of its share of capacity and energy on a "take-or-pay" basis. For the Fiscal Year ended June 30, 2009, PVNGS provided 72,606 MWh of energy to the City at an average cost for delivered power of $80 per MWh.

SCPPA has issued bonds for PVNGS of which $89,470,000 aggregate principal amount was outstanding as of May 1, 2010. SCPPA has undertaken certain actions, including collections of amounts in excess of operating and maintenance expenses and current debt service on its bonds for PVNGS to reduce the cost of power from this project. The City, as well as the Cities of Azusa, Banning, Burbank, Colton, Glendale, Los Angeles, Riverside and Vernon and the Imperial Irrigation District ("IID") are PVNGS project participants.

The SCPPA PVNGS Interest consists of a 5.91% ownership interest in the Palo Verde Nuclear Generating Station, Units 1, 2 and 3, and certain associated facilities and contractual rights relating thereto, a 5.56% ownership interest in the Arizona Nuclear Power Project ("ANPP") High Voltage Switchyard and contractual rights relating thereto and a 6.55% share of the rights to use certain portions of the Arizona Nuclear Power Project Valley Transmission System. PVNGS is located on an approximately 4,000-acre site about 50 miles west of Phoenix, Arizona and is comprised of three identical nuclear-fueled steam units. PVNGS Units 1, 2 and 3 achieved firm operation in January 1986, September 1986 and December 1987, respectively. Each unit, designed for a 40-year life, has a nominal rating of 1,270 MW. Each PVNGS unit is currently rated at 3,893 MW (thermal). The maximum dependable capacity of Units 1, 2 and 3 under adverse atmospheric conditions is 1,243 MW, 1,243 MW and 1,247 MW, respectively. Transmission is accomplished through agreements with Salt River Project Agricultural Improvement and Power District ("Salt River Project"), LADWP and SCE.

In 1997 SCPPA began taking steps designed to accelerate the payment of all fixed rate bonds relating to PVNGS. Such steps consisted primarily of refunding certain outstanding bonds for savings and accelerating payments by the PVNGS project participants on the bonds issued by SCPPA for PVNGS. The restructuring plan has resulted in substantial savings to the City, and the delivered cost of energy produced by PVNGS decreased significantly on July 1, 2004. See "Indebtedness and Joint Agency Obligations" below and TABLE 9 – "OUTSTANDING DEBT OF JOINT POWERS AGENCIES."

Magnolia Power Project. The City is a participant in the Magnolia Power Project, a gas-fired generating facility with a nominally rated net capacity of 242 MW and auxiliary facilities located in Burbank, California. Through a contract with SCPPA, the City is entitled to a 6.4% (15.5 MW base capacity and about 19 MW peaking capacity) entitlement in the project through a long-term power purchase agreement with SCPPA. SCPPA has entered into power sales agreements with the City and the Cities of Anaheim, Burbank, Cerritos, Colton, Glendale and Pasadena pursuant to which SCPPA has sold 100% of its entitlement to capacity and energy in the Magnolia Project to such participants on a "take-or-pay" basis. The Magnolia Power Project commenced commercial operation on September 22, 2005. SCPPA issued bonds to finance the construction of the Magnolia Power Project, of which $379,750,000 aggregate principal amount was outstanding as of May 1, 2010 (of which $13,195,000 relates exclusively to the City of Cerritos). PWP has entered into a power sales agreement with SCPPA for an approximate 6.4% participation share in the Magnolia Power Project and is therefore responsible for 6.4% of the costs of the Magnolia Power Project.

Prepaid Natural Gas Project. The Prepaid Natural Gas Project provides, through Gas Sales Agreements with the participants in the Prepaid Natural Gas Project, for a secure and long-term supply of natural gas. The original agreement provided the City with a supply of approximately 2,000 MMBtu daily or 730,000 MMBtu annually at a discounted price below spot market price (the SoCal Index) for a 30 year term. The projected discount of approximately 90 cents per MMBtu was expected to result in savings of approximately $657,000 annually, or approximately $19.7 million over the next 30 years.

On October 22, 2009, the Gas Sales Agreement with SCPPA was restructured to provide an acceleration of a portion of the long-term savings over the next three years, reduce the remaining volumes of gas to be delivered and shorten the overall duration of the agreement. The restructured agreement provides additional savings of approximately $2,700,000 through 2012 with the remainder to be realized over the new term of the transaction. Total expected savings from the project are not impacted by the restructuring. The restructured agreement will terminate in 2035 compared to the original termination year of 2038. The volumes of gas to be delivered are reduced from approximately 2,000 MMBtu to 1,340 MMBtu daily at a projected discount of approximately 98 cents per MMBtu. As a result of this restructuring, approximately $165,000,000 worth of outstanding aggregate principal bonds were retired. As of May 1, 2010, SCPPA had outstanding $333,370,000 aggregate principal amount of bonds issued for the Prepaid Natural Gas Project. SCPPA will bill the City for actual quantities of natural gas delivered each month. PWP expects that these costs will be recovered through the energy charge component of the electric rates as they are incurred, just as costs for natural gas purchases are currently recovered.

Milford Wind Corridor Phase I Project The City entered into a Power Sales Agreement with SCPPA for 2.5% (approximately 5 MW) of the output (including capacity, energy and associated environmental attributes) of Milford Wind Corridor Phase I Project, a 203.5 MW nameplate capacity wind farm comprised of 97 wind turbines located near Milford, Utah. The facility is owned by Milford Wind Corridor Phase I, LLC, a limited liability company organized and existing under the laws of the State of Delaware. The facility went into commercial operation on November 16, 2009. Energy from the facility is delivered over an approximately 90-mile, 345 kV, transmission line extending from the wind generation site to the IPP Switchyard in Delta, Utah, which transmission line, together with certain structures, facilities, equipment, fixtures, improvements and associated real and personal property interests and other rights and interests necessary for the ownership and operation of the generation facility and the sale of power therefrom, comprise a part of the Milford facility. The City is able to accept the delivered facility energy utilizing its capacity rights in the IPP Switchyard that are provided under agreements relating to the IPP. The facility energy is then delivered over the Southern Transmission System of IPP to the Adelanto or Marketplace terminal in California utilizing the City's capacity rights in the IPP Southern Transmission System and other transmission systems. See "Transmission Resources – Existing Transmission Resources – Southern Transmission System" below. The facility energy delivered at Adelanto or Marketplace is then transmitted to the City under certain transmission arrangements between LADWP or the ISO and the City and certain transmission arrangements between the City and Southern California Edison Company. As of May 1, 2010, SCPPA has outstanding $237,235,000 aggregate principal amount of bonds issued primarily for the purpose of prepaying for a guaranteed annual quantity of energy from the facility for approximately 20 years. See also "Renewable Resources – Current Renewable Projects" below.

Remote Ownership Interests

Hoover Hydroelectric Project Interest. The City has a 20 MW capacity entitlement from the generating units at the hydroelectric power plant of the Hoover Dam (the "Hoover Project"), located approximately 25 miles from Las Vegas, Nevada. Modern insulation technology has made it possible to "uprate" the nameplate capacity of existing generators (the "Hoover Uprating Project"). The Hoover Uprating Project consists principally of the uprating of the capacity of 17 generating units at the Hoover Project. The City, as well as the Cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Riverside and Vernon have obtained entitlements totaling 127 MW of capacity and approximately 143,000 megawatt-hours ("MWh") of allocated energy annually from the Hoover Uprating Project. In 1987, to reflect these entitlements, these cities entered into contracts with the United States Bureau of Reclamation (the "Bureau") providing for the advancement of funds for the uprating and with the Western Area Power Administration ("Western") for the purchase of power from the Hoover Project. The City's capacity entitlement is comprised of an 11 MW renewal and 9 MW resulting from the uprating. The actual capacity available from the Hoover Project varies, depending on maintenance scheduling and other outages. Under normal hydrologic conditions, the City receives approximately 60

GWh of annual energy deliveries. In the Fiscal Year ended June 30, 2009, the Hoover Project provided 51,208 GWh of energy to the City at an average cost for delivered power of $15 per MWh.

Natural Gas Project. The Natural Gas Project includes SCPPA's leasehold interests in (i) certain natural gas resources, reserves, fields, wells and related facilities located near Pinedale, Wyoming and (ii) certain natural gas resources, reserves, fields, wells and related facilities in (or near) the Barnett Shale geological formation in Texas. The capital costs of the entitlement shares purchased by certain participants were financed through SCPPA by the issuance of project revenue bonds. The City and the City of Glendale contributed capital to SCPPA for the payment of their respective shares of the capital costs of the Natural Gas Project. SCPPA has sold the entire production capacity of its member-related leasehold interests, on a "take-or-pay" basis (with the City and the City of Glendale having no obligation to pay any debt service).

Purchased Power

In addition to City-owned resources and interests in the joint-venture generation projects, the City has long-term contractual arrangements for Electric System firm purchases, as well as enabling agreements, including Western Systems Power Pool ("WSPP") membership, which allow short term power transactions in markets throughout the Western United States and Canada. Each of these resources is briefly described below.

Bonneville Power Administration Purchase Exchange Contract. The City executed a 20-year seasonal capacity for energy exchange agreement with the Bonneville Power Administration ("BPA") in May 1995 for up to an additional 15 MW of firm capacity (and attendant energy) in the summer. BPA provides 15 MW of firm capacity and approximately 15 GWh of peak hour energy from May through September. Under the terms of the agreement, the City returns approximately 30 GWh of off-peak, non-firm energy from September through March. This contract provides capacity to the City through Fiscal Year 2014-15.

Renewable Resource Purchases. The City has also entered into certain power purchase agreements in furtherance of its adopted renewable resource portfolio standard. See "Renewable Resources" below.

Bilateral (Spot Market) Energy Purchases. Approximately 15-30% of PWP's annual energy needs are met through economic purchases of spot market power through short-term bilateral transactions. These transactions, which range in duration from one hour to one year, are made pursuant to the WSPP, of which the City has been a member since 1995. The WSPP is governed by a master enabling agreement with over 175 member utilities and power marketers that allows short-term transactions of one year or less for capacity, energy or transmission at negotiated market prices. This agreement replaced several obsolete agreements with individual utilities that typically had rate requirements above market price, while simultaneously providing access by the City to a much larger, growing market for bulk power transactions. In addition, this agreement allows for the purchase of firm capacity to meet spinning reserve requirements, providing the City with potential additional savings. In the event of excess electric and gas commodity and transmission capacity, the City enters into short-term bilateral sales transactions in order to offset costs.

Renewable Resources

General

On October 13, 2003, the City Council adopted a renewable portfolio standard (the "RPS") for PWP. The City Council adopted a new RPS on March 16, 2009. The new RPS calls for the addition of cost-effective renewable resources to meet 15% of the City's retail electric energy needs by 2010 through a combination of long-term and short-term power purchases, 33% by 2015 and 40% by 2020. On September 18, 2006 the City adopted the United Nations Urban Environmental Accords and endorsed the US Mayors' Climate Protection Agreement. One of the City's goals under the UEA is to reduce greenhouse gas (GHG) emissions to 7% below 1990 levels by 2012. The City also fully supports and actively strives to fulfill the principles of environmental laws passed by the State legislature in recent years:

Assembly Bill 32 ("AB 32"), the "California Global Warming Solutions Act of 2006: Greenhouse Gases," was signed into law on September 27, 2006. AB 32 is intended to reduce California's GHG emissions to 1990 levels by 2020.

Senate Bill 107 ("SB 107"), which accelerates the State's RPS to require retail sellers of electricity (excluding municipal utilities) to procure at least 20% of their retail sales from renewable power by 2010 instead of 2017. Municipals are requested by the legislation to similarly accelerate their RPS goals.

Senate Bill 1037 ("SB 1037"), requires that each publicly owned electric utility ("POU"), including PWP, prior to procuring new energy generation resources, first acquire all available energy efficiency, demand reduction, and renewable resources that are cost effective, reliable and feasible. SB 1037 also requires each municipal electric utility to report annually to its customers and to the California Energy Commission (the "CEC") its investment in energy efficiency and demand reduction programs.

Assembly Bill 2021 ("AB 2021") requires municipal electric utilities to identify all potentially achievable cost-effective electricity efficiency savings and to establish annual targets for energy efficiency savings and demand reduction over the next 10 years and to report those targets to the CEC within 60 days of adoption, and annually a description of its energy efficiency and demand reduction programs, expenditures, cost-effectiveness and actual results and the results of an independent evaluation that measures and verifies the EE savings and reduction in energy demand achieved by its EE and DR programs. AB 2021 further requires publicly owned POUs to "treat investments made to achieve energy efficiency and demand reduction targets as procurement investments."

Assembly Bill 1368 ("AB 1368"), sets limits on carbon dioxide (CO_2), emissions of new contracts signed by utilities in California.

Senate Bill 1078 ("SB 1078"), which became law January 1, 2003, requires local publicly-owned utilities to establish and implement a renewable portfolio standard that "recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect on rates, reliability, financial resources and the goal of environmental improvement." SB 1078 also requires that each local publicly owned utility report to its customers, on an annual basis, the fuel mix used to serve its customers and the expenditure of public goods funds for renewable resources.

For additional information regarding the legislation referred to above, see "DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS – State Legislation" herein.

In 2006, the City adopted its energy efficiency ("EE") and demand reduction ("DR") program goals to reduce forecast peak demand in 2012 by 10% and forecast annual energy consumption in 2016 by 13.3% in accordance with the City's Urban Environmental Accords ("UEA") goals and AB 2021. Shortly thereafter, the City adopted solar photovoltaic ("PV") incentive program, with the goal of installing 14 MWs of customer owned PV systems in ten years and assist the City in meeting certain UEA goals. Relevant UEA policies include: (i) reduce greenhouse gas ("GHG") emissions 25% by 2030; (ii) reduce the city's peak electric load by 10% by 2012; and (iii) increase the use of renewable energy to meet 10% of the City's peak electric load by 2012. The EE and DR program supports three of the City's UEA goals (Renewable Energy, Energy Efficiency, and Climate Change). The program goals will also help PWP meet the goals of two other state laws, including AB 32 and SB 1037.

In 2007, the City Council approved an ordinance creating a commission advisory to the City Council known as the Environmental Advisory Commission (the "EAC"). The EAC holds monthly open meetings to the public and serves as a forum for the discussion of environmental issues with local, regional, and global impacts. Its nine commissioners include seven appointed by the City Council, one appointed by the mayor, and one appointed by the mayor from persons recommended by the seven Council members. PWP will provide Fiscal Year results to the EAC by October of each year, such reports having commenced in October 2007 for Fiscal Year 2006-07. In addition, EE, DR, and PV technologies, avoided costs, and program potential were reviewed as part of the independent review of the Integrated Resource Plan (described below).

Integrated Resource Plan

On March 16, 2009, the City Council approved the 2009 Integrated Resource Plan for PWP, a 20-year strategic power resource plan that establishes broad objectives and an overall direction for future policy, program and procurement decisions with respect to PWP's power supply resource portfolio. The 2009 Integrated Resource Plan identifies PWP's preferred resource mix for satisfying its electric power requirements, consisting of energy efficiency, demand side management resources, renewable resources and other supply side resources over the 20-year planning horizon. Implementation of the identified preferred resource mix would include: (i) reducing PWP's reliance on its existing coal resources (IPP), (ii) replacing the aging steam generating unit at the Broadway generating facility and replacing it with a comparably sized new combined cycle plant, (iii) upgrading the existing Glenarm generating units in order to extend their operating lives, (iv) implementation of additional energy efficiency and load management programs, (v) increasing PWP's renewable resources consistent with the new RPS adopted by the City Council (see "Renewable Resources – General" above), (vi) increasing PWP's customer-owned photovoltaic installations, (vii) establishing a feed-in tariff program in order to procure additional qualifying renewable resources located within the City and (viii) achieving $CO2$ emission reductions in accordance with the following timeline: 5% by 2010, 25% by 2015 and 40% by 2020. The 2009 Integrated Resource Plan is based on certain assumptions and forecasts and therefore is expected to evolve as it is implemented over the 20-year time frame.

Current Renewable Projects

In order to meet the City's Renewable Portfolio Standard targets as described under "Renewable Resources – General" above, the City will continue to procure additional renewable resources through SCPPA as well as independent negotiations with renewable resources providers. The following is a list of the City's current renewable projects:

High Winds Wind Generation Facility. In 2003 the City Council of the City approved a 25-year power purchase agreement with PPM for the purchase of wind-powered electrical energy associated with a 6 MW (or approximately 17,500 MWh per year) share of the High Winds wind generation facility which provided 2 MW of power to PWP in 2004. The High Winds Project is a 145.6 MW wind generation facility located in Solano County, California. PPM will be responsible for scheduling the wind energy as it is produced at the High Winds Project into the California ISO. PPM will re-deliver the associated energy on a firm basis to a delivery point in Southern California, providing PWP with a constant, reliable source of energy. The wind generation contract is in compliance with SB 1078 and the RPS. The contract increases PWP's renewable energy to approximately 17.5 GWh per year.

Landfill Gas Generator Projects. The City signed two Purchased Power Agreements for electricity from landfill gas generator projects diversifying its Renewable Resources Portfolio. The City receives 9.5 MW from Minnesota Methane's generating plant, a pre-existing landfill gas generator project located in Southern California. The City will receive 6.67 MW from Ameresco's gas-turbine landfill gas generating plant which is also located in Southern California but is still under construction. Delivery of power from Ameresco is not expected to commence until [June 2010].[to be updated as date nears]

Milford Wind Corridor Phase I Wind Generation Project. As described above, the City is a participant in SCPPA's Milford Wind Corridor Phase I Project, a new 203.5 MW wind generating facility located in Millard County, Utah and a power sales agreement with SCPPA for an approximately 5 MW (2.5%) share of the project. The project serves the goals established by the City's RPS for PWP and aids the City in achieving its environmental goals. This new renewable resource will help PWP meet load without additional GHG emissions in alignment with SB 32 and SB 1368. With this agreement, PWP will have exceeded its current RPS goals established in 2003 and approach the accelerated RPS of SB 107. The project began commercial operation in November 2009.

Solar and Photovoltaic. PWP's solar program has been in existence since 1999 and has provided rebates to 118 residential and 15 nonresidential customers for the installation of grid-tied photovoltaic (PV) systems. Annual funding for customer PV programs between 1999-2007 averaged $100,000 and was focused on small residential systems due to the availability of state-funded incentives for systems larger than 30 kW. Typical residential PV systems range from 2-3 kW and provide 30%-80% of the customer's energy needs. Since 2008, the Pasadena Solar Initiative (PSI) program has offered incentives for PV systems up to 1 MW. PWP's current incentives are available to residential and business customers and are based on either the expected performance (ranges from $2-$3.15 per watt) or actual performance (ranges from $0.30-$0.47 per kWh).

Energy Efficiency Programs. PWP currently offers a wide range of residential and business customer energy efficiency (EE) programs that are funded from PBC revenues. PWP's EE programs yielded almost 17,000 MWh of energy savings per year and 3.2 MW of peak demand reduction in Fiscal Year 2008-09, representing 1.3% and 1.1% of annual energy load and peak demand, respectively. EE programs such as the Energy Star and Refrigerator Replacement Program are cost effective and very popular with residential customers. EE projects for nonresidential customers funded by PWP's Energy Efficiency Partnering (EEP) and Direct Install of Emerging Technologies (DIET) programs accounted for approximately 65% of EE savings and 72% of peak load reduction in Fiscal Year 2008-09.

PWP leverages its PBC funding through joint action with SCPPA that is coordinated through the SCPPA Public Benefits Committee. This has been particularly effective in procuring cost-effective efficient appliances and program services and consulting. The SCPPA Public Benefits Committee meets monthly to share information, develop and compare programs, prepare requests for proposals, and assess pending and new legislation or regulations.

Additional Projects. PWP is currently reviewing other potential options with respect to additional renewable resources, including possible biogas (bio methane) fuel projects at certain of its power plants. PWP expects to expects to procure additional renewable resources towards satisfying its

RPS targets. With the inclusion of the above-described resources, it is expected that approximately 12% of PWP's energy portfolio will be supplied from renewable resources by December 31, 2010.

Fuel Supply

PWP's local generating units are fueled by natural gas. PWP has firm transportation contracts to deliver about 4,000 MMBtu per day, which is approximately two thirds of the annual average daily consumption. Peak natural gas consumption can exceed 30,000 MMBtu per day. The Southern California Gas Company ("SCG") provides intra-state delivery of PWP's natural gas supplies. PWP has Firm Access Rights ("FAR") for an average of approximately 2,100 MMBtu per day to transport gas from TW Needles to Socal Citygate to meet its natural gas demand. Gas commodity is subject to reserve leaseholds and prepayment agreements as described herein, purchased on a term basis in forward markets, and also at monthly and daily index rates. During peak months, gas requirements in excess of firm capabilities and long term supply contracts are purchased at the Southern California Citygate.

PWP has access to Canadian gas via firm transportation on the Nova, Transcanada, and Pacific Gas & Electric ("PG&E") expansion into the SCG system, netting about 3,989 MMBtu/day at Kern River Station in Kern County, California.

In addition, the City is a participant in SCPPA's Natural Gas Project, consisting of leasehold interests in natural gas fields located in Wyoming and Texas, and its Prepaid Natural Gas Project Gas Sales Agreements which provide a supply at prices below spot market price through 2035. These supplies are expected to account for an average of approximately 1,940 MMBtu/day or approximately 33% of PWP's average daily natural gas consumption. See "Joint Powers Agency Generation and Fuel Resources/Remote Ownership Interests – Southern California Public Power Authority – Prepaid Natural Gas Project" and "– Remote Ownership Interests – Natural Gas Project."

The cost of natural gas has been volatile over recent years. The City is not able to determine or project what the future cost of natural gas will be.

Transmission Resources

General

In January 2005, the City became a Participating Transmission Owner ("PTO") in the ISO and placed certain transmission facilities and entitlements to transmission service on certain facilities under the ISO's operational control. Pursuant to the ISO Tariff and applicable Federal Energy Regulatory Commission ("FERC") precedent, FERC approved a Base Transmission Revenue requirement ("TRR") and a Transmission Revenue Balancing Account Adjustment ("TRBAA") for the City to recover the costs of these facilities and entitlements.

The City has been filing annual updates to its TRBAA with FERC since becoming a PTO. The TRBAA is the mechanism by which transmission revenue credits associated with transmission service from the ISO are flowed through to transmission customers. The TRBAA amount is used as an offset to the Transmission Revenue Requirement of a Participating Transmission Owner. The TRBAA does not change the Base TRR nor does it flow through transmission cost increases to PTOs. Any change to the Base TRR requires that a petition must be filed with FERC.

In August 2009, the City filed a petition with FERC to revise its Base TRR to recover the costs increases the City has been experiencing since FERC approved its initial Base TRR. In December 2009, FERC approved the City's petition and increased the City's TRR by approximately $2.4 million effective

October 1, 2009.

Existing Transmission Resources

Transmission resources are an integral component of the City's plan to provide economical and reliable electric service to its customers. The City currently has several firm capacity transmission agreements to deliver over 200 MW of remote generation to the T.M. Goodrich Receiving Station in the City, and to provide access to major hubs of the western wholesale power market. The transmission network allows the City to obtain low-cost energy supplies when available, enable bulk sales and exchanges of energy during low-load periods, and take advantage of price differentials between various locations on the Western Electricity Coordinating Council ("WECC") power grid through wheeling, arbitrage sales and energy swaps. Depending on the generation source, the energy is transmitted through a combination of the transmission resources listed in the following table.

TABLE 5
FIRM TRANSMISSION SERVICE AGREEMENTS

Transmission Line Path	Owner/Party	Capacity
Sylmar-T.M. Goodrich	SCE/ISO[1]	200 MW
Pacific-Northwest DC Intertie	Pasadena	45 MW[2]
Northern Trans. System (NTS)	IPA/Utah	104 MW
Southern Trans. System (STS)	SCPPA	113 MW
Adelanto-Sylmar	LADWP	136 MW
Mead-Phoenix	SCPPA	33 MW
Mead-Adelanto	SCPPA	70 MW
McCullough-Victorville	Pasadena	25 MW
Victorville-Sylmar	LADWP	26 MW
Hoover-Sylmar	LADWP	26 MW

Source: Power Supply Business Unit of PWP.

(1) The ISO became the control area operator and scheduling agent for this line commencing with ISO operations.

(2) The City owns 69 MW of transmission capacity in this line. 24 MW of transmission capacity has been sold to the Cities of Azusa, Banning, Colton, Anaheim and Riverside.

Southern California Edison. The City has a transmission contract with SCE for rights to 200 MW of firm transfer capacity from LADWP's Sylmar Substation to the T. M. Goodrich Receiving Station in the City through SCE, as well as an interconnection agreement with SCE for interconnection of the T.M. Goodrich Receiving Station to the SCE system Beginning on March 31, 1998, the ISO became the scheduling agent for the transmission contract. This transmission contract expires in August 2010 and is not expected to be renewed. Upon expiration of the transmission contract, the City will continue to have access to the Sylmar-Goodrich transmission line under the ISO tariff. The City joined the ISO in 2005 as a Participating Transmission Owner in order to facilitate the transmission of resources without further contracting with the SCE power distribution system and as a PTO, the City will have full access to the this transmission at the ISO tariff rate. A successor to the City's interconnection agreement with SCE for interconnection of the T.M. Goodrich Receiving Station to the SCE system is currently being negotiated and the renewal is expected to be in place prior to the August 2010 expiration.

Pacific Northwest DC Intertie. Spanning 850 miles from Celilo in northern Oregon to Sylmar, California, the Pacific Northwest DC Intertie is a double-pole, ±500 kV transmission line. The Pacific Northwest DC Intertie conveys energy to the City from BPA and other Pacific Northwest utilities. PWP is entitled to 69 MW (2.25%) of the total 3,100 MW capacity of the southern portion (south of the point where the line crosses the Nevada-Oregon Border ("NOB") of the Pacific Northwest DC Intertie). Because of the load diversity and excess hydroelectric energy in the spring, the Pacific Northwest DC Intertie provides the City many opportunities for energy imports.

Northern Transmission System. The Northern Transmission System consists of two 50-mile long 345 kV AC transmission lines which connect the IPP to the Mona Substation in Utah and the Gonder Substation in Nevada. The City has entitlements of up to 104 MW of capacity on these transmission lines as a result of the IPP Excess Sales Contract with the Utah Participants. IPA allocates 2.4735% of its outstanding debt to the Northern Transmission System. As of May 1, 2010 this allocation was approximately $65.7 million. The City's maximum share of this obligation is 6%.

Southern Transmission System. The Southern Transmission System ("STS") is a double-pole, ±500 kV DC transmission line spanning 488 miles from IPP in central Utah to the Adelanto Substation in Southern California, together with an AC/DC converter station at each end. It is operated and maintained by the LADWP under contract with IPA. In connection with its entitlement to the IPP, the City acquired a contractual entitlement to 113 MW (5.88%) of the total 1,920 MW capacity of the STS through a transmission system contract with SCPPA. The term of this contract extends for the life of facility, or until all SCPPA bonds issued to finance the STS are defeased. There is a large potential of wind and geothermal renewable energy resource development available in Central Utah and in order to have access to the potential energy in that area, the California participants in IPP initiated the STS Upgrade project, which will increase the capacity of the transmission by 480 MW. The cost of the project is expected to be $125 million and was bond financed by SCPPA in December 2008. The STS Upgrade project is expected to be in commercial operation by December 31, 2010. As of May 1, 2010, SCPPA had outstanding $900,705,000 principal amount of its bonds issued to finance the STS (including the STS Upgrade project). The City has entered into a transmission service contract with SCPPA which obligates the City to pay the cost of its share of the transfer capability on a "take-or pay" basis.

Adelanto-Sylmar Transmission Line. The Adelanto-Sylmar Transmission Line is a continuation of the Southern Transmission System. The City has a contract with LADWP for 136 MW of transmission capacity from either Adelanto or Victorville to Sylmar.

Mead-Phoenix Transmission Project. The Mead-Phoenix Transmission Project consists of a 256-mile, 500 kV AC transmission line, which was placed into commercial operation on April 15, 1996, extending between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. The line is looped through the new 500-kV switchyard constructed in the existing Mead Substation in southern Nevada with a transfer capability of 1,300 MW. By connecting to Marketplace Substation, the Mead-Phoenix Transmission Project interconnects with the Mead-Adelanto Transmission Project (as described below) and with the existing McCullough Substation. The Mead-Phoenix Transmission Project is comprised of three project components. SCPPA has executed an ownership agreement providing it with an 18.3077% member-related ownership share in the Westwing-Mead project component, a 17.7563% member-related ownership share in the Mead Substation project component, and a 22.4082% member-related ownership share in the Mead-Marketplace project component. Other owners of the line are Arizona Public Service Company, M-S-R Public Power Agency, Salt River Project and Starwood Energy Infrastructure Fund, L.P. The commercial operation date for the project was April 15, 1996. The City has entered into a transmission service contract with SCPPA which obligates the City to pay the cost of its share of the transfer capability (13.8%) on a "take-or-pay" basis. The term of this contract extends for the life of the facility, or until all SCPPA bonds issued to finance the project are defeased. As of May 1, 2010, SCPPA had outstanding $60,640,000 principal amount of its bonds issued to finance its interest in the Mead-Phoenix Transmission Project.

Through its contract with SCPPA, the City is entitled to receive 33 MW of this line's 1,320 MW transfer capability.

Mead-Adelanto Transmission Project. This arterial line consists of a 202- mile, 500 kV AC transmission line extending between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation, a substation located approximately 17 miles southwest of Boulder City, Nevada. By connecting to Marketplace Substation, the line interconnects with the Mead-Phoenix Transmission Project and the existing McCullough Substation in southern Nevada. The line has a transfer capability of 1,200 MW. SCPPA has executed an ownership agreement providing it with a total of a 67.9167% member-related ownership share in the project. The other owners of the line are M-S-R Public Power Agency and Starwood Energy Infrastructure Fund, L.P. The commercial operation date for the project was April 15, 1996, which coincided with the completion of the Mead-Phoenix Transmission Project. The City has entered into a transmission system contract with SCPPA which obligates the City to pay the cost of its share of the transfer capability (8.6%) on a "take-or-pay" basis. The term of this contract extends for the life of the facility, or until all SCPPA bonds issued to finance the project are defeased. As of May 1, 2010, SCPPA had outstanding $190,440,000 principal amount of its bonds issued to finance its interest in the Mead-Adelanto Transmission Project. Through its contract with SCPPA, the City is entitled to 70 MW of this line's transfer capability.

McCullough-Victorville Transmission Line. The City acquired a 25 MW equity entitlement from LADWP in the 180-mile, 500 kV AC McCullough-Victorville No. 2 Transmission Line. Originally utilized to import the City's PVNGS power, this line provides a parallel path to the Mead-Adelanto transmission line into the critical Mead Substation.

Victorville-Sylmar. The City contracts with LADWP for 26 MW of firm transmission service from the Victorville Substation to the Sylmar Substation as a continuation of the McCullough-Victorville Line.

Hoover-Sylmar Transmission Agreements. The City has executed contracts for transmission service to transfer its Hoover renewal (11 MW), its uprate entitlement (9 MW), and an additional 6 MW for other uses concurrent with the terms of the Hoover entitlement. As a result of these contracts, the City's total Hoover transmission entitlement is 26 MW.

Future Transmission Resources

PWP has transmission resources throughout the west to deliver contractual and spot market supplies into the California ISO grid at the Sylmar interconnection with LADWP, about 10 miles from the City. All of PWP's external resources use this interconnection. As previously noted, PWP has 200 MW rights from Sylmar to the City under contract with SCE that provide firm "Existing Transmission Contract" rights under the ISO, which contract expires in August 2010. Following the contract expiration, PWP, as a Participating Transmission Owner, can continue to take delivery of this related energy by wheeling it through the ISO at the tariff rate. See "OTHER FACTORS – Changes in Federal Regulation of Electric Utilities" herein.

Inter-Utility Sales Transactions

In addition to making market purchases when economical, PWP also sells excess electric and gas commodity and transmission capacity when the City does not need it. The City has entered into a number of long-term capacity sales, and energy schedulers and dispatchers also respond to opportunities to market excess power when conditions warrant. The additional net revenues from these transactions help keep electricity rates down by offsetting fixed energy costs. PWP's current inter-utility transactions are summarized as follows:

Pacific Northwest DC Transmission Service Agreements. Under these agreements, the City provides up to 24 MW of long-term transmission service to the purchasers over the City's entitlement in the Pacific Northwest DC Intertie Project. During Fiscal Year 2008-09, transmission service charge revenues from these agreements were approximately $1 million. The Pacific Northwest DC Transmission Service Agreements expired in 2009.

California ISO – Participating Generator Agreement. Under this agreement, the City sells capacity and energy from its local generation resources at Broadway and Glenarm into the California ISO's ancillary service markets on a day-ahead and hour-ahead basis. Revenues were extraordinary in Fiscal Year 2000-01 as a result of regional power shortages experienced at that time, yielding more than $67 million in revenue. Some of these revenues may be subject to refund as a result of ongoing litigation, and approximately $19.6 million of these revenues remain unpaid by the ISO as of July 1, 2009. As a result, the City has posted a net receivable of approximately $11 million. Due to the short-term nature of the market, these ancillary service capacity and energy revenues are extremely volatile and difficult to predict; however, it is expected that they will range from $3 to 10 million annually in the future.

Interconnections and Distribution Facilities

PWP owns facilities for the distribution of electric power within the city limits of the City (approximately 23 square miles). These facilities include approximately 78 miles of 34 kV subtransmission circuits, 190 miles of 17 kV power lines, 281 miles of 4 kV distribution circuits, 2 receiving stations (including the T.M. Goodrich Receiving Station) and 11 major substations. The City's system experienced approximately 1.51 hours of outage time per customer during Fiscal Year 2008-09.

Employees

For Fiscal Year 2009-10, the City has 306 full-time equivalent employees for the Electric System. All Electric System employees are represented either by the International Brotherhood of Electrical Workers, the International Union of Operating Engineers, the American Federation of State, County and Municipal Employees, the Pasadena Association of Clerical and Technical Employees or Pasadena Management Association in all matters pertaining to wages, benefits and working conditions. The current arrangements with these unions and/or associations, which are in the form of either a contract or a memorandum of understanding, expire by their respective terms on various dates through 2012, at which time each is expected to be subject to renegotiation. See APPENDIX A – "THE CITY OF PASADENA – Employee Relations."

The Electric System's permanent employees are all covered by the California Public Employees Retirement System ("PERS"), administered by the State, to which contributions are made by both the City and the employees. As of June 30, 2008 (the latest available information), the actuarial staff of PERS reported unfunded liability of $59.0 million for the City's miscellaneous employees as compared to an underfunding of $46.2 million the previous year. As of June 30, 2008, the City reported that its PERS obligation with respect to the City's miscellaneous employees was 90.7% funded.

The City provides a subsidy to retirees of the City that are members of PERS (as well as members of the Pasadena Fire and Police Pension System) toward the purchase of medical insurance from PERS. Benefit provisions are established and amended through negotiations between the City and the respective unions. As of June 30, 2008, the City reported its unfunded actuarial accrued liability for these post-retirement benefits of $23.7 million. The City funds these benefits on a "pay-as-you-go" basis.

Insurance

The insurable property and facilities of the Electric System are covered under the City's general insurance policies. The City does not carry earthquake insurance on the property and facilities of the Electric System. For additional information on the City's insurance, see APPENDIX A – "THE CITY OF PASADENA – Insurance."

Electric Rates and Charges

The City is obligated by its Charter and by its rate ordinance to establish rates and collect charges in an amount sufficient to meet its expenses of operation and maintenance and debt service requirements (with specific requirements as to priority and coverage). See "SECURITY AND SOURCES OF PAYMENT FOR THE 2010A BONDS – Rate Covenant." Electric rates are subject to approval by the City Council. Electric rates are not subject to regulation by the CPUC or by any other state agency. Although its rates are not subject to approval by any federal agency, the City is subject to certain ratemaking provisions of the federal Public Utility Regulatory Policies Act of 1978 ("PURPA"). The City believes that it is operating in compliance with PURPA. See "OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY – Federal Rate Regulation" herein.

PWP's electric rate structure is unbundled into distribution, energy and transmission, does not allow cross subsidy among customer classes, is cost based, includes a 1.85% PBC rider, and includes variable components, which recover cost increases from customers associated with energy and transmission. The City provides no free electric service. The following table sets forth rates for each customer class as of June 30, 2005 through June 30, 2009.

TABLE 6
FIVE-YEAR HISTORY OF ELECTRIC RATES
Dollars Per Kilowatt Hour

	Fiscal Year Ended June 30,				
Customer Class	**2005**	**2006**	**2007**	**2008**	**2009**
Residential	$0.1146	$0.1184	$0.1310	$0.1396	$0.1495
Small Commercial and Industrial	0.1095	0.1127	0.1239	0.1332	0.1427
Medium Commercial and Industrial	0.1062	0.1070	0.1176	0.1258	0.1346
Large Commercial and Industrial	0.1024	0.1038	0.1124	0.1189	0.1242
Street Lighting and Traffic Signals	0.0932	0.1008	0.1159	0.1241	0.1321

Source: Finance and Administration Business Unit of PWP.

Electric rates have been generally stable over the past five years. PWP plans to change rates as necessary to reflect changes in purchase power costs, operating and capital costs.

Reserve Policies

General

During the past few years PWP has, in practice, had cash balances that exceeded 30 days of operating expenses on hand in accordance with reserve policies formalized in May 2006 as a matter of policy and not pursuant to any bond indenture or agreement. PWP was as of June 30, 2009, and currently is, in compliance with such policies. These funds represent moneys required for unanticipated operational expenses, as well as approved capital expenditures, unexpended public benefit fund moneys and reserves for energy and transmission cost increases. The following table sets forth actual reserves at June 30, 2009, for each fund. Reserve levels are calculated in accordance with PWP's reserve policy.

Reserves	($ million)
Operating Reserve	26.0
Energy Reserve	17.9
Transmission Reserve	5.6
Contingency Reserve	0.5
Bond Service Reserve	6.3
Unexpended Bond Proceeds	18.1
PBC Reserve	2.3
Capital Reserve	40.0
Total	$116.7

Source: Finance and Administration Business Unit of PWP.

Operating Reserve. The operating reserve policy provides for 60 days of operations and maintenance expenses. As of June 30, 2009, PWP had about $26 million in operating reserves.

Energy Reserve. The energy reserve account is to mitigate energy cost volatility and unexpected plant outages, which have to be covered by power purchased in the energy markets. The reserve amount is driven mainly by a periodic assessment of PWP's load forecast, the amount of power required to be purchased in the energy markets to supplement power already secured through long-term commitments and past purchases, and the estimated near-term forecast of natural gas and power costs.

Transmission Services Charge Reserve. This reserve account is a depository account for balancing costs and revenues associated with high-voltage transmission and related services.

Contingency Reserve. The Contingency Reserve is designated for equipment replacement and/or emergency work due to natural disasters.

Bond Service Reserve. This reserve is a depository account for bond debt service reserves funds held by the City for PWP bonds.

Unexpected Bond Proceeds. This is a depository account for bond proceeds that have not been expended on capital projects.

Public Benefit Charge (PBC) Reserve. This reserve account is a depository account for balancing costs and revenues associated with the PBC Program and it is used exclusively to fund PBC related expenditures.

Capital Reserve. This reserve account is designated to fund the design and construction costs of near-term committed capital projects. PWP generally maintains a cash flow budget for key capital projects and ensures that it has on hand sufficient funds to cover its current year ongoing capital projects. Currently, PWP is utilizing the Capital Reserve to cover its pay-as-you-go portion of the financing required for its Power Distribution System Master Plan projects. The balance of the financing for these near-term committed projects was derived from net proceeds of the 2008 Bonds.

Stranded Investment Reserve

In addition to the foregoing reserves, the City maintains a Stranded Investment Fund, which was established in 1997 to mitigate the difference between the costs associated long-term contracts with IPA and SCPPA, and the anticipated energy costs in a deregulated energy market. The City estimated at that time that the cost of energy under the IPA and SCPPA contracts resulted in a net present value of the "stranded investments" of $150 million. Since the City's stranded costs are related to power contracts which may not at present be prepaid economically, the City established a Reserve for Stranded Investment (the "Stranded Investment Reserve") and imposed a Stranded Investment Surcharge (the "SIS") on all electric utility bills, which was fully funded by June 30, 2001. Amounts in the Stranded Investment Reserve may be drawn upon in any year, as needed, to offset the City's stranded cost, if any, in that year. In 2006, PWP implemented a Stranded Investment Reserve Utilization Plan which included the following:

Direct Defeasance. The Stranded Investment Reserve Utilization Plan called for a commitment of approximately $80 million to offset the City's debt service requirements for IPP bonds.

In January 2009, PWP implemented this plan component with the economic defeasance of approximately $70.02 million of IPP bonds representing approximately $80 million of the City's share of the outstanding debt service requirements for IPP bonds. This direct defeasance was completed pursuant to the IPP Prepayment Agreement among IPA and each of the California Purchasers, including PWP. Under this arrangement, PWP prepaid a portion of the outstanding IPP bonds by making funds available to IPA to purchase U.S. Treasury Securities - State and Local Government Series (SLGS) on its behalf. In return, IPA issued corresponding subordinated notes to PWP and agreed to make debt service payments to PWP. As PWP receives the scheduled debt service payments from the subordinated notes, these payments will be used to offset the total monthly power costs of the City's IPA power bills and offset any potential increases in power costs to customers.

Refund Excess Funds. The Stranded Investment Reserve Utilization Plan called for the transfer of $15 million from the Stranded Investment Reserve to the Power Cost Adjustment Charge Fund (PCACF) as a mechanism to "refund" this amount to customers during the remainder of Fiscal Years 2006-07 and 2007-08.

Between November 2006 and June 2008, PWP utilized $15 million of excess funds in the Stranded Investment Reserve by transferring this amount to the Power Cost Adjustment Charge Fund (PCACF) to offset potential increases in power costs to customers. The transfers were made over a two year period to minimize impact on the City's investment.

Contingent Mitigation. The Stranded Investment Reserve Utilization Plan called for the retention of approximately $50 million in the Stranded Investment Reserve to mitigate variable and unexpected costs resulting from very low market conditions, increases in power costs or outages associated with IPP or Palo Verde, with the duration of investments to support contingent mitigation to be structured to meet cash flow requirements.

As of June 30, 2009, the Stranded Investment Reserve Fund balance was $59.7 million. This amount was reflected on the Statement of Net Assets for the Light and Power Fund as restricted cash. PWP projects that the amount, which exceeds the identified $50 million required for contingent mitigation under the Stranded Investment Reserve Utilization Plan, plus future interest earnings will be sufficient to cover uncertainties associated with the long-term commitments for energy from IPP.

Customers, Energy Sales and Revenues

The average number of customers, energy sales and revenues derived from sales, by classification of service, during the past five Fiscal Years, are listed below.

TABLE 7
CUSTOMERS, ENERGY SALES AND REVENUES

	Fiscal Year Ended June 30,				
	2005	2006	2007	2008	2009
Number of Customers:					
Residential	53,174	53,989	54,315	54,378	54,826
Small Commercial & Industrial	7,314	7,356	7,202	7,475	7,724
Medium Commercial & Industrial	751	744	824	866	866
Large Commercial & Industrial	144	155	160	160	161
Public Street & Highway Lighting	6	6	6	6	6
Total	61,389	62,250	62,507	62,885	63,583
Megawatt-hour Sales:					
Residential	313,470	314,235	337,905	338,855	337,531
Small Commercial & Industrial	158,719	157,731	162,329	158,103	155,978
Medium Commercial & Industrial	262,161	269,360	264,846	262,736	257,540
Large Commercial & Industrial	409,643	435,573	453,485	462,644	474,180
Public Street and Highway Lighting	18,669	16,841	16,332	16,288	16,266
Other (Unbilled)	8,369	(6,119)	9,045	(7,212)	3,513
Total Retail Energy Sales	1,171,029	1,187,621	1,243,942	1,231,414	1,245,008
Wholesale Sales to Other Utilities	125,250	27,816	122,496	315,484	118,231
Total Energy Sales	1,296,279	1,215,437	1,366,439	1,546,898	1,363,240
Revenues from Sale of Energy:					
Residential	$ 35,937,447	$ 37,213,497	$ 44,266,214	$ 47,163,611	$ 50,460,525
Small Commercial & Industrial	17,376,458	17,781,408	19,994,651	21,001,083	22,256,838
Medium Commercial & Industrial	27,831,108	28,827,639	31,144,843	32,957,566	34,668,843
Large Commercial & Industrial	41,726,502	44,861,113	50,962,878	54,846,816	58,897,519
Wholesale Sales to Other Utilities	5,500,117	5,662,420	5,012,333	8,150,682	10,774,433
Public Street & Highway Lighting	1,739,353	1,697,249	1,893,208	2,016,645	2,149,495
Other (1)	8,530,662	13,941,927	14,263,882	12,943,793	13,950,533
Total Energy Revenue	$138,641,647	$149,985,253	$167,538,009	$185,043,797	$193,158,186

Source: Finance and Administration Business Unit of PWP.
(1) Other revenue includes PTO – TRR revenues, Public Benefit Charge, unbilled revenue and miscellaneous governmental revenue.

Within PWP, "commercial and industrial" customers are principally educational and healthcare institutions and office buildings, as well as a wide range of businesses. These businesses include postal service, engineering, telecommunications, healthcare, property development, insurance, office products and packaging and chemical products. No single commercial industrial customer currently accounts for more than 3% of total annual electrical sales revenue. The top 20 commercial and industrial customers typically represent approximately 15% of PWP's annual electric sales revenue.

Capital Requirements

In March 2005, the City Council adopted the Power Master Plan which identified the infrastructure needs of the power distribution system and recommended system improvements over a 20-year planning period (2005 - 2025). Following the adoption of the Power Master Plan, PWP engaged R.W. Beck to develop a detailed capital improvement project implementation and spending plan for the first six years of the Power Master Plan. This implementation and spending plan was completed in July 2005. The implementation and spending plan recommended that PWP make a capital investment of about $121.9 million in its power distribution system through 2011. This recommended capital investment was in addition to other planned capital projects of about $74.4 million over the same period and did not include any new investments for energy supply. Specifically, the implementation and spending plan requires PWP to augment the power distribution system capacity, install additional equipment and replace aging infrastructure. Over 17 specific projects were identified for the first six years of the Power Master Plan as well as associated resource requirements and costs. PWP made significant progress on these projects.

The City expects routine capital requirements, including those contemplated by the Power Master Plan and those relating to the City's planned local gas-fired generation project repowering, for the next five Fiscal Years to aggregate approximately $369 million. It is expected that on average, approximately 35 percent of these improvements are expected to be funded through current revenues and the balance will be funded through the issuance of future financings.

TABLE 8
CAPITAL REQUIREMENTS
(In Thousands)

Fiscal Year	Capital Requirements
2011	$ 59,630
2012	98,738
2013	102,419
2014	60,791
2015	47,431
Total	$369,009

Indebtedness and Joint Agency Obligations

Upon the issuance of the 2010A Bonds and the refunding of the Refunded 2002 Bonds, in addition to the 2010A Bonds, the City will have outstanding $________* aggregate principal amount of Bonds which are payable from the Light and Power Fund and secured by a pledge of the Net Income of the Electric System. See "SECURITY AND SOURCES OF PAYMENT FOR THE 2010A BONDS" herein.

As previously discussed, the City participates in the SCPPA joint powers agency. SCPPA provides for the financing and construction of electric generating and transmission projects for participation by some or all of its members. The City is a participant in the following SCPPA projects:

* Preliminary, subject to change.

PVNGS, Hoover, Magnolia Power Project and Milford Wind Corridor Phase I Project, with respect to generation, and is a participant in the Mead-Phoenix Transmission Project, the Mead-Adelanto Transmission Project and the Southern Transmission System with respect to transmission. To the extent the City participates in projects developed by SCPPA, the Electric System is obligated for its proportionate share of the cost of the particular project. See TABLE 9 – "OUTSTANDING DEBT OF JOINT POWERS AGENCIES." In 1997 SCPPA began taking steps designed to accelerate the payment of all fixed rate bonds relating to PVNGS. Such steps consisted primarily of refunding certain outstanding bonds for savings and accelerating payments by the PVNGS project participants on the bonds issued by SCPPA for PVNGS. The restructuring plan has resulted in substantial savings to the City, and the delivered cost of energy produced by PVNGS decreased significantly on July 1, 2004.

In addition, the City has entered into certain power sales contracts with IPA and others for the delivery of electric power from IPP. The Electric System's share of IPP power is equal to 6.0% of the generation output of IPP, IPA's 1,660 MW coal-fueled generating station, located in central Utah. The contracts constitute an obligation of the Electric System to make payments solely from revenues from the Light and Power Fund. The power sales contracts also require the Electric System to pay certain minimum charges that are based on debt service requirements. Such payments are considered a Maintenance and Operating Expense as a cost of purchased power.

Obligations of the City under the agreements with IPA and SCPPA constitute Maintenance and Operating Expenses of the City payable prior to any of the payments required to be made on the Bonds. Agreements between the City and SCPPA and the City and IPA (other than the agreement relating to SCPPA's Natural Gas Prepaid bonds) are on a "take-or-pay" basis, which requires payments to be made whether or not applicable projects are operating or operable, or whether the output from such projects is suspended, interfered with, reduced, curtailed or terminated in whole or in part. In addition, all of these agreements (other than the agreement relating to SCPPA's Natural Gas Prepaid bonds) contain "step up" provisions obligating the City to pay a share of the obligations of a defaulting participant. Such payments represent the Electric System's share of current and long-term obligations. Payment for these obligations will be made from operating revenues received during the year that payment is due. The City's participation and share of principal obligations (without giving effect to interest due on the obligations or any "step up" provisions) for each of the joint powers agency projects in which it participates are shown in the following table.

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TABLE 9
OUTSTANDING DEBT OF JOINT POWERS AGENCIES
As of May 1, 2010

	Outstanding Debt	City's Participation[1]	City's Share of Outstanding Debt[2]
IPA			
Intermountain Power Project[3]	$2,656.2	6.0%	$159.4[3]
SCPPA			
Palo Verde Project	89.5	4.4	3.9
Southern Transmission System	900.7	5.9	53.1
Mead-Adelanto Transmission Project	190.4	8.6	16.4
Mead-Phoenix Transmission Project	60.6	13.8	8.4
Magnolia Power Project[4]	366.6	6.4	23.5
Milford Wind Corridor Phase I Project	237.2	2.5	5.9
Natural Gas Prepaid	333.4	16.5	55.0
TOTAL	$4,834.6		$325.6

Source: Finance and Administration Business Unit of PWP.

(1) Participation obligation is subject to increase upon default of another project participant (other than with respect to SCPPA's Natural Gas Prepaid bonds).

(2) Excludes interest on the debt.

(3) Includes commercial paper, subordinate notes and full accreted value at maturity for all capital appreciation bonds. Includes IPP bonds defeased with funds provided by the City as described under "– Reserve Policies – Stranded Investment Reserve" above for which the City is the payee of a subordinate note receivable from IPA of approximately [$70,020,000] outstanding as of May 1, 2010.

(4) Excludes bonds relating solely to City of Cerritos.

(5) City payment obligation is with respect to actual quantity of natural gas delivered each month on a take-and-pay basis. Responsibility for bond repayment is non-recourse to the City. See "Joint Powers Agency Generation and Fuel Resources/Remote Ownership Interests – Southern California Public Power Authority – Prepaid Natural Gas Project" above.

For the Fiscal Year ended June 30, 2009, the City's payments of debt service on its joint powers agency obligations aggregated approximately $29.1 million. As of May 1, 2010, a portion of the joint powers agency obligation debt service was variable rate debt. Unreimbursed draws under liquidity arrangements supporting joint powers agency variable rate debt obligations bear interest at rates well in excess of the current variable rate on such bonds. Moreover, in certain circumstances, the failure to reimburse draws on the liquidity agreements may result in the acceleration of scheduled payment of the principal of such variable rate joint powers agency obligations. There are currently no unreimbursed draws under such liquidity arrangements outstanding, although draws have on occasion been made as a result of market conditions during the last two years resulting in unremarketed variable rate bonds for certain periods. In addition, swap agreements entered into by the joint powers agencies in connection with certain of such obligations are subject to early termination under certain circumstances, in which event the joint powers agency could owe substantial termination payments to the applicable swap provider (an allocable portion of such payments the project participants would be obligated for).

Historical Operating Results and Debt Service Coverage

The following table shows the historical operating results and debt service coverage during the past five Fiscal Years on PWP's parity obligations payable from PWP's Light and Power Fund.

TABLE 10
HISTORICAL OPERATING RESULTS AND DEBT SERVICE COVERAGE
(Dollar Amounts in Thousands)

	Fiscal Year Ended June 30,				
	2005	2006	2007	2008	2009
Revenues:					
Base Rate Operating Revenues	$ 35,085	$ 34,082	$ 47,665	$54,091	$ 51,481
Recovered Energy & Transmission Costs	90,017	96,271	100,261	103,895	116,226
PTO – TRR Revenues [(1)]	4,418	10,621	10,581	8,340	7,298
Public Benefit Charge	3,306	3,249	3,391	3,407	7,194
Sales to Other Utilities	5,499	5,662	5,012	13,705	10,775
Other Operating Revenues	316	100	628	1,606	184
Total Operating Revenues	$138,641	$149,985	$167,538	$185,044	$193,158
Expenses:					
Energy Costs – Fuel					
Retail	$ 6,745	$ 8,025	$ 8,187	$ 12,958	$ 17,800
Wholesale	1,284	0	785	1,307	1,667
Purchased Power					
Retail	68,561	84,208	80,000	82,309	78,575
Wholesale	0	0	0	8,189	3,332
Direct Operating Expenses	14,719	15,691	16,290	19,090	20,303
General and Administrative (includes Commercial)	14,392	14,974	15,354	16,650	24,294
Interest Expense	6,300	5,937	6,017	6,508	7,720
Depreciation	13,858	14,227	14,652	15,708	16,737
Total Expenses	$125,859	$143,062	$141,286	$162,719	$170,428
Earnings from Operations	$ 12,782	$ 6,923	$ 26,252	$ 22,325	$ 22,730
Non Operating Income	15,263	8,283	20,091	17,639	14,078
Net Income	$ 28,045	$ 15,206	$ 46,342	$ 39,964	$ 36,808
Cash Flow and Debt Service Calculation					
Add Back Interest Expense	$ 6,300	$ 5,937	$ 6,017	$ 6,508	$ 7,720
Add Back Depreciation	13,858	14,227	14,652	15,708	16,737
Available for Debt Service	$ 48,203	$ 35,370	$ 67,011	$ 62,180	$ 61,265
Debt Service	$ 13,875	$ 12,677	$ 12,855	$ 13,713	$ 14,930
Debt Service Coverage	3.70x	2.79x	5.21x	4.53x	4.10x
Amount Available After Debt Service	$ 34,328	$ 22,693	$ 54,156	$ 48,467	$ 46,335

Source: City of Pasadena Department of Finance.
(1) Participating Transmission Owner – Transmission Revenue Requirement Revenues. Effective January 1, 2005, Pasadena became a PTO.

Condensed Balance Sheet

The following Condensed Balance Sheet has been prepared by the City based upon audited financial statements for the Fiscal Years shown.

TABLE 11
CITY OF PASADENA
ELECTRIC UTILITY FUND
CONDENSED BALANCE SHEET
(Dollar Amounts in Thousands)

	Fiscal Year Ended June 30,				
	2005	**2006**	**2007**	**2008**	**2009**
Total Current & Non-Current Assets	$115,787	$ 94,510	$112,248	$114,944	$241,993
Total Restricted Assets	155,299	156,740	155,962	219,848	84,843
Net Property, Plant and Equipment	254,067	262,034	279,742	297,663	316,773
Total Assets	$525,153	$513,284	$547,952	$632,455	$643,609
Total Current Liabilities	17,583	18,719	20,249	24,663	19,551
Net Long Term Liabilities	130,397	123,354	116,047	167,513	159,893
Net Assets	$377,173	$371,211	$411,656	$440,279	$464,165

Source: City of Pasadena Department of Finance.

Electric System Initiatives

In addressing the changing legal and business environment resulting from efforts to restructure the electric utility business in California the City undertook a number of strategic efforts to ensure that the Electric System remained competitive. Strategic efforts have been undertaken in the past several years to allow the Electric System to retain customers by maintaining high quality service and competitive rates.

DEVELOPMENTS IN THE CALIFORNIA ENERGY MARKETS

Background; California Electric Market Deregulation

In 1996, California partially deregulated its electric energy market. As a consequence of the partial deregulation, the California investor-owned utilities (the "IOUs") sold a large portion of their generation resources and began to purchase significant amounts of electricity. During portions of 2000 and 2001, the market price of electricity in California went through significant fluctuations; the impacts of which are well documented.

A number of state and federal proceedings began as a result of the market dysfunction of 2000 and 2001. These included investigations into alleged market manipulation, which for the most part have either ended or are in the final appellate stages. Other proceedings are ongoing, such as litigation at FERC regarding the need for refunds due to the alleged overcharging for the sale of electricity (which proceedings initially included sales by municipal utilities but were dismissed for lack of jurisdiction). Other cases have been or are expected to be remanded to FERC after appeals to the Ninth Circuit. Although it was ultimately found that FERC lacked jurisdiction to order refunds for alleged overcharging by non-jurisdictional entities, several plaintiffs have pursued remedies in state and federal courts based on a contract and quasi-contract theory. The City is unable to predict the final outcome of existing investigations and proceedings regarding California's energy crisis or whether further investigations, proceedings, litigation or other actions will follow.

During 2000 and 2001, California experienced extreme fluctuations in the prices and supplies of natural gas and electricity in much of the State. Licenses for new power plants have been issued by the CEC, construction on several power plants has been completed and construction of additional power plants is underway. However, progress on new transmission line projects within California has been slow. Therefore, while there has been some progress in addressing these issues, uncertainty remains. There has also been ongoing substantial volatility in the cost of natural gas, which is the fuel source for many of California's electric generating units. State agencies have issued warnings that further power shortages are possible for Southern California. As a result of the foregoing and other factors, no assurance can be given that measures undertaken during the last several years, together with measures to be taken in the future, will prevent the recurrence of shortages, price volatility or other energy problems that have adversely affected PWP and other California electric utilities in the past.

City's Response to Market Deregulation – Direct Access

Following the dysfunction in the market and the energy crisis in 2000 and 2001, Assembly Bill 1X ("AB 1X") was enacted to authorize the State to begin procuring power for the retail customers of the investor-owned utilities. AB 1X also required the CPUC to suspend the right of retail customers of purchase electricity from suppliers other than the State Department of Water Resources and the investor-owned utilities. Pursuant to AB 1X, on March 21, 2002, the CPUC suspended direct access and customer choice programs for the retail customers of the California investor-owned utilities. However, in October 2009, California Senate Bill 695 ("SB 695") was signed into law, which deletes the existing suspension of direct access transactions for investor-owned utilities and instead requires the CPUC to authorize direct access transactions for nonresidential end-use customers subject to a phase-in schedule of not less than three years and not more than five years, and subject to an annual maximum allowable total kilowatt hour limit established for each investor-owned utility. On March 11, 2010, the CPUC approved a decision to implement the provisions of SB 695, setting the gigawatt direct access load limits for each of the three California investor-owned utilities and providing for a four year phase-in schedule beginning April 11, 2010.

A ten-year financial plan for PWP, which was first presented to the City Council in September 1996 (the "Power Deregulation Plan") is now prepared on a five year basis and details all operating income and expenses as well as balance sheet items. The Power Deregulation Plan targeted the phase-in of direct access for all City customer classes beginning January 1, 2000. Under direct access, customers may choose to purchase electricity from other energy suppliers. In April 1999, the City Council approved a Direct Access Phase-In Schedule, Direct Access Regulation No. 22, a non-bypassable generation related charge and amended the Light and Power Rate Ordinance to establish, among other things, the following two items: (1) a Direct Access Energy Credit, providing that those customers who choose to purchase their power from an energy supplier other than PWP will continue to pay the currently established electric rates, except for the energy supply component of the rate, and (2) a Direct Access Charge, providing that all customers who choose to participate in direct access will be required to pay all incremental and ongoing costs incurred by PWP to implement direct access. The purpose of these actions was to allow PWP to collect any stranded costs which may arise as well as any ongoing incremental costs related to direct access from any customers who choose to leave PWP as a result of direct access. To date PWP has not lost any customers due to the implementation of direct access.

State Legislation

A number of bills affecting the electric utility industry have been introduced or enacted by the

California Legislature. In general, these bills provide for reduced greenhouse gas emission standards and greater investment in energy-efficient and environmentally friendly generation alternatives through more stringent renewable resource portfolio standards. The following is a brief summary of certain of these bills.

Greenhouse Gas Emissions. On June 1, 2005, the Governor signed Executive Order S-3-05, which placed an emphasis on efforts to reduce greenhouse gas emissions by establishing statewide greenhouse gas reduction targets. The targets are: (i) a reduction to 2000 emissions levels by 2010; (ii) a reduction to 1990 levels by 2020; and (iii) a reduction to 80% below 1990 levels by 2050. The Executive Order also called for the California Environmental Protection Agency to lead a multi-agency effort to examine the impacts of climate change on California and develop strategies and mitigation plans to achieve the targets. On April 25, 2006, the Governor also signed Executive Order S-06-06 which directs the State to meet a 20% biomass utilization target within the renewable generation targets of 2010 and 2020 for the contribution to greenhouse gas emission reduction.

The Governor signed Assembly Bill 32, the Global Warming Solutions Act of 2006 (the "GWSA"), which became effective as law on January 1, 2007. The GWSA prescribed a statewide cap on global warming pollution with a goal of reaching 1990 greenhouse gas emission levels by 2020. In addition, the GWSA establishes a mandatory reporting program for all IOUs, municipal utilities and other load-serving utilities to inventory and report greenhouse gas emissions to the California Air Resources Board ("CARB") and requires CARB to adopt regulations for significant greenhouse gas emission sources (allowing CARB to design a "cap-and-trade" system) and gives CARB the authority to enforce such regulations beginning in 2012. On December 11, 2008, CARB adopted a "scoping plan" to reduce greenhouse gas emissions which includes a mixed approach of market structures, regulation, fees and voluntary measures. The scoping plan includes a cap-and-trade system that covers 85% of all California greenhouse gas emissions and will be implemented in coordination with the Western Climate Initiative regime, which is a regional zone consisting of seven states and three Canadian provinces that is in the process of establishing a greenhouse gas trading framework. CARB has begun developing regulations for greenhouse gas emissions limits and reduction measures. The regulations will go into effect and be enforceable beginning January 1, 2012.

On November 24, 2009, CARB released its Preliminary Draft Regulation for a California Cap and Trade Program for public review and comment. By summer 2010, CARB is anticipating that its 45-day public review period for the regulation will commence and that CARB will consider the final draft at its October 2010 meeting. The timeline set by CARB to develop, finalize and begin implementation of the cap and trade regulation indicates that the program is scheduled to be launched by the GWSA deadline of January 1, 2012. The City may be adversely affected by implementation of an auction type cap-and-trade system, which would require the City to purchase carbon credits to offset the higher than average carbon emissions of its resource portfolio.

In addition to the GWSA, Senate Bill 1368 also became effective as law on January 1, 2007 and provides for an emission performance standard, restricting new investments in baseload fossil fuel electric generating resources that exceed the rate of emissions for greenhouse gases for existing combined-cycle natural gas baseload generation and seeks to allow the CEC to establish a regulatory framework necessary to enforce the greenhouse gas emission performance standard for publicly-owned utilities. The CPUC has the similar responsibility for the IOUs. The revised proposed CEC regulations were approved by the Office of Administrative Law on October 16, 2007. The regulations promulgated by the CEC prohibit any investment in baseload generation that does not meet the emission performance standard of 1,100 pounds of CO_2 per MWh of electricity, with limited exceptions for routine maintenance, requirements of pre-existing contractual commitments, or threat of significant financial harm.

Meanwhile, Assembly Bill 1925, signed by the Governor on September 26, 2006, requires the CEC to develop a cost effective strategy for the geologic sequestration and management of industrial carbon dioxide. Also on September 26, 2006, the Governor signed Senate Bill 1686 ("SB 1686"), which authorizes the Wildlife Conservation Board (the "WCB") to take into account the potential of forestlands to beneficially reduce or sequester greenhouse gas emissions when it prioritizes funds available for proposed acquisitions. SB 1686 also specifies that the WCB may use policies, protocols and other relevant information developed by the California Climate Action Registry in determining a project's potential to reduce or sequester greenhouse gas emissions.

Energy Procurement and Efficiency Reporting. Senate Bill 1037 ("SB 1037"), signed by the Governor on September 29, 2005, requires that each municipal electric utility, including the City, prior to procuring new energy generation resources, first acquire all available energy efficiency, demand reduction, and renewable resources that are cost effective, reliable and feasible. SB 1037 also requires each municipal electric utility to report annually to its customers and to the CEC its investment in energy efficiency and demand reduction programs.

Further, Assembly Bill 2021 ("AB 2021"), signed by the Governor on September 29, 2006, requires that the publicly-owned utilities establish, report, and explain the basis of the annual energy efficiency and demand reduction targets by June 1, 2007 and every three years thereafter for a ten-year horizon. Future reporting requirements under AB 2021 include: (i) the identification of sources of funding for the investment in energy efficiency and demand reduction programs; (ii) the methodologies and input assumptions used to determine cost-effectiveness; and (iii) the results of an independent evaluation to measure and verify energy efficiency savings and demand reduction program impacts. The information obtained from the local publicly-owned utilities is being used by the CEC to present the progress made by the publicly-owned utilities on the State's goal of reducing electrical consumption by 10% in ten years and amelioration with the greenhouse gas targets presented in Executive Order S-3-05 signed by the Governor on June 1, 2005. In addition, the CEC will provide recommendations for improvement to assist each local publicly-owned utility in achieving cost-effective, reliable, and feasible savings in conjunction with the established targets for reduction. In accordance with AB 2021, the City adopted energy efficiency "goals" or targets on September 24, 2007.

Renewable Portfolio Standards. In September 2002, the California Legislature enacted and the Governor signed into law Senate Bill 1078 ("SB 1078"). SB 1078 requires that the IOUs adopt a Renewable Portfolio Standard ("RPS") to meet a minimum of 1% of retail energy sales needs each year from renewable resources and to meet a goal of 20% of their retail energy needs from renewable energy resources by the year 2017. SB 1078 also directed the State's municipal electric utilities to implement and enforce an RPS that recognizes the intent of the Legislature to encourage development of renewable resources, taking into consideration the impact on a utility's standard on rates, reliability, financial resources, and the goal of environmental improvement. The City has adopted an RPS as required by SB 1078. On September 26, 2006, the Governor signed Senate Bill 107 into law, which requires IOUs to have 20% of their electricity come from renewable sources by 2010 and prescribes that municipal utilities meet the intent of the legislation. On November 17, 2008, the Governor signed Executive Order S-14-08. Among other things, Executive Order S-14-08 provides that the RPS target established for California shall require retail electricity sellers to serve 33% of their loads with eligible renewable energy resources by 2020. On September 15, 2009, the Governor signed Executive Order S-21-09. Executive Order S-21-09 provides, among other things, that CARB is to establish a regulation consistent with the 33% RPS target established in Executive Order S-14-08 by July 31, 2010 and that CARB work with the CEC and CPUC to ensure that such regulation will build upon the existing RPS program and will regulate all California load serving entities, including publicly-owned utilities. CARB is currently conducting its Renewable Electricity Standard ("RES") proceeding to develop such regulation. In addition, Executive Order S-21-09 provides that CARB may delegate policy development and implementation to CEC and

CPUC, that CARB is to consult with California Independent System Operator ("ISO") and other balancing authorities on impacts on reliability, renewable integration requirements and interactions with wholesale power markets in carrying out the provisions of Executive Order S-21-09, and that CARB is to establish the highest priority for those resources with the least environmental costs and impacts on public health that can be developed most quickly and that support reliable, efficient and cost-effective electricity system operations, including resources and facilities located throughout the Western interconnection. In 2010, Senate Bill 722 ("SB 722") was re-introduced, which would establish a 33% by 2020 RPS target. As currently proposed, SB 722 would make certain requirements of the RPS program applicable to local publicly-owned electric utilities, including the 33% by 2002 RPS target applicable to the IOUs under the proposed bill. In its current form, SB 722 includes certain provisions allowing for utilities to meet a portion of their RPS requirements through the use of renewable energy certificates ("RECs") (further discussed below) that are not delivered with renewable energy.

Since the implementation of SB 1078, the CPUC and the CEC have taken a number of actions that have had an impact on the renewable energy goals set by the legislation. In order to overcome the challenges associated with meeting accelerated RPS goals, the CPUC and the CEC supported the implementation of a renewable energy certificate ("REC") trading system to meet the accelerated RPS goals. SB 107 allows this flexibility, with the condition that the energy is delivered to an in-state trading hub. In parallel, pursuant to SB 1078, the CEC, collaboratively with the Western Governors' Association and the WECC, has established the Western Renewable Energy Generation Information System ("WREGIS"), which is expected to ensure the integrity of RECs and prevent the double counting of the certificates. The electronic tracking system became operational in 2007. On March 11, 2010, the CPUC issued a Decision in Rulemaking 06-02-012, which authorizes the use of WREGIS in tracking RECs that are sold and traded by various participants, including the state's IOUs. The Decision provides guidance on the temporary use of tradable RECs for the IOUs to comply with RPS requirements and sets a temporary cap on the costs of tradable RECs. The Decision is also being applied as guiding policy in the use of RECs under CARB's RES proceeding.

Solar Power. On August 21, 2006, the Governor signed into law Senate Bill 1 (also known as the "California Solar Initiative"). This legislation would require municipal utilities, including the City, to establish a program supporting the stated goal of the legislation to install 3,000 MW of photovoltaic energy in California. Municipal utilities are also required to establish eligibility criteria in collaboration with the CEC for the funding of solar energy systems receiving ratepayer funded incentives. The legislation gives a municipal utility the choice of selecting an incentive based on the installed capacity, starting at $2.80 per watt, or based on the energy produced by the solar energy system, measured in kilowatt-hours. Incentives would be required to decrease at a minimum average rate of 7% per year. Municipal utilities also have to meet certain reporting requirements regarding the installed capacity, number of installed systems, number of applicants, amount of awarded incentives and the contribution toward the program's goals.

Future Regulation

The electric industry is subject to recurrent reform. States routinely consider changes to the way in which they regulate the electric industry. Recently, both further deregulation and forms of additional regulation have been proposed for the industry, which has been highly regulated throughout its history. The City is unable to predict at the time the impact any such considerations will have on the operations and finances of PWP or the electric utility industry generally.

Impact of Developments on the City

The effect of these developments in the California energy markets on the City cannot be fully ascertained at this time. Also, volatility in energy prices in California may return due to a variety of factors which affect both the supply and demand for electric energy in the western United States. These factors include, but are not limited to, the adequacy of generation resources to meet peak demands, the availability and cost of renewable energy, the impact of greenhouse emission legislation and regulations, fuel costs and availability, weather effects on customer demand, transmission congestion, the strength of the economy in California and surrounding states and levels of hydroelectric generation within the region (including the Pacific Northwest). This price volatility may contribute to greater volatility in the Electric System's revenues from the sale (and purchase) of electric energy and, therefore, could materially affect the financial condition of the Electric System.

OTHER FACTORS AFFECTING THE ELECTRIC UTILITY INDUSTRY

Federal Energy Legislation

Energy Policy Act of 2005. In August 2005, then President Bush signed the Energy Policy Act of 2005 ("EPAct 2005"). EPAct 2005 expands FERC's jurisdiction to require municipal utilities that sell more than eight million MWhs of energy per year to pay refunds under certain circumstances for sales into organized markets. EPAct 2005 also provides for mandatory reliability standards to increase system reliability and minimize blackouts, in addition to criminal and civil penalties for manipulative energy trading practices. EPAct 2005 authorizes FERC to issue permits to construct or modify transmission facilities located in a national interest electric transmission corridor if FERC determines that the statutory conditions are met. EPAct 2005 also requires the creation of an electric reliability organization ("ERO") to establish and enforce, under FERC supervision, mandatory reliability standards to increase system reliability and minimize blackouts. Failure to comply with such mandatory standards exposes a utility to significant fines and penalties by the ERO.

Under EPAct 2005, IOUs must offer each of its customer classes a time-based rate schedule to enable customers to manage energy use through advanced metering and communications technology. It authorizes FERC to exercise eminent domain powers to construct and operate transmission lines if FERC determines a state has unreasonably withheld approval. EPAct 2005 contains provisions designed to increase imports of liquefied natural gas and incentives to support renewable energy technologies, including a new program for tax credit bonds for local governments, like the City, to finance certain renewable energy facilities. EPAct 2005 also extends for 20 years the Price-Anderson Act, which concerns nuclear power liability protection and provides incentives for the construction of new nuclear plants.

The City is unable to predict at this time the impact that EPAct 2005 will have on the operations and finances of their respective electric systems or the electric utility industry generally.

NERC Reliability Standards. EPAct 2005 required FERC to certify an ERO to develop mandatory and enforceable Reliability Standards, subject to FERC review and approval. The Reliability Standards apply to users, owners and operators of the Bulk-Power System, as more specifically set forth in each Reliability Standard. On February 3, 2006, FERC issued Order 672, which certified the North American Electric Reliability Corporation ("NERC") as the ERO. Many Reliability Standards have since been approved by FERC.

The ERO or the entities to which NERC has delegated enforcement authority through an agreement approved by FERC ("Regional Entities"), such as the WECC, may enforce the Reliability